BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-_____**

DIRECT TESTIMONY

OF

SETH E. CUREINGTON

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

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I. INTRODUCTION AND PURPOSE

A. Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Seth E. Cureington. My business address is 1600 Perdido St., New Orleans, Louisiana 70112.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy New Orleans, Inc., ("ENO" or the "Company") as Director, Resource Planning and Market Operations. In that capacity, among other activities, I provide resource planning services to ENO.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am filing this Direct Testimony before the Council of the City of New Orleans (the "Council") on behalf of ENO.

Q4. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR, RESOURCE PLANNING AND MARKET OPERATIONS?

A. As Director of ENO's Resource Planning and Market Operations department, I am responsible for providing oversight to all of ENO's integrated resource planning efforts, implementation plans, as well as market operations in the Midcontinent Independent System Operator, Inc. ("MISO") regional transmission organization ("RTO"). I also serve as the Chairman of the Entergy New Orleans Operating Committee.

Q5. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in 2001 and a Master of Science in Economics in 2004 from Louisiana State University.

I began my career with Entergy Services, Inc. ("ESI")[1] as a Senior Analyst with the System Planning and Operations ("SPO") organization in 2006, where I was responsible for providing technical and analytical support for a wide range of commercial and supply procurement activities for the EOCs. I remained with SPO for the following six years, during which time I was promoted to the role of Senior Wholesale Executive with the Commercial Operations Group where I was responsible for leading the technical and commercial evaluation of all long-term generation supply opportunities in support of the EOCs' portfolio transformation initiative. In 2011, I joined ENO's Regulatory Affairs organization as Manager, Resource Planning where I was responsible for providing oversight to the development of ENO's integrated resource plans and providing guidance and analytical support to ENO's Regulatory Affairs group with respect to the integrated resource planning process. In 2013, my responsibilities were expanded to include oversight of market operations MISO, and in June 2016 I was promoted to Director, Resource Planning and Market Operations.

1 ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), ENO, and Entergy Texas, Inc. ("ETI").

Q6. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE COUNCIL?

A. Yes. I have attached as Exhibit SEC-1 a listing of my prior testimony before the Council.

B. Purpose and Summary of Testimony

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of the Company in support of its Application for approval to construct the New Orleans Power Station, a 226 MW combustion turbine ("CT") generating unit to be located at the Company's Michoud generating facility in New Orleans, Louisiana ("NOPS").

Q8. PLEASE PROVIDE A BRIEF OVERVIEW OF THE REASONS FOR PROPOSING NOPS.

A. Recent unit deactivations (which were economic decisions based on maintenance and other operational issues) have left the Company short of both its overall long-term capacity needs and its long-term peaking and reserve capacity needs. The deactivated units (ENO's Michoud Units 2 and 3) provided a significant source of local generating capacity within the Company's service area (*i.e.*, Orleans Parish) in support of reliable operations and mitigated supply- and market-related risks. As discussed more fully below, going forward, the Company is proposing NOPS to address these and other long-term needs.

NOPS is proposed to be located in Orleans Parish, which complies with the Council's prior directive to use reasonable diligent efforts to site a generating resource within Orleans Parish. Moreover, as also discussed more fully below, while the Company continues to support the addition of cost effective demand-side management ("DSM") programs[2] and renewable resources to its portfolio, neither offer a cost-effective or lower-risk alternative sufficient to obviate the need for NOPS. In addition, deferring the timely deployment of new peaking and reserve capacity resources and instead relying on the MISO capacity market to meet long-term capacity needs will expose the Company's customers to increased cost and risk. For these reasons, the Company requests that the Council approve the construction of NOPS.

Q9. PLEASE ELABORATE ON THE COMPANY'S LONG-TERM CAPACITY NEEDS.

A. The recent deactivation of Michoud Units 2 and 3 resulted in the loss of approximately 781 MW of local capacity (which is approximately [redacted] of ENO's 2016 forecasted non-coincident peak load). As a result, ENO has an overall long-term need for capacity as well as a long-term need for local peaking and reserve capacity resources. While the acquisition of Power Block 1 of the Union Power Station ("Power Block 1") helped to offset a substantial portion of ENO's overall capacity needs (including baseload and load-following needs), the Company has an

2 The term DSM includes both energy efficiency and demand response programs. For example, ENO currently operates Energy Smart, which is a comprehensive energy efficiency program that provides incentives for energy efficient measures, including energy audits, direct install CFL bulbs, low flow fixtures, weatherization, HVAC and A/C tune-ups, and lighting. Demand response programs typically are designed to reduce demand during peak hours. An example would be a thermostat that can turn off air conditioning in response to commands from the utility.

overall remaining long-term capacity need of approximately 124 MW in 2016 and up to 205 MW by 2030. Moreover, current projections show that ENO has an existing long-term need for approximately 288 MW of peaking and 118 MW of reserve capacity resources in 2016, which need is expected to persist throughout the planning horizon absent the addition of new resources capable of meeting those needs. Prior to deactivation, Michoud Units 2 and 3 helped meet a portion of those needs by providing the Company's only source of local capacity within its service area (*i.e.*, Orleans Parish).

Q10. HAVE THE COMPANY'S EXISTING DSM AND RENEWABLE RESOURCES BEEN TAKEN INTO CONSIDERATION IN ESTABLISHING THE IDENTIFIED LONG-TERM NEEDS?

A. Yes. The Company's existing portfolio of DSM and renewable resources has been accounted for and do not obviate the need for NOPS. The Energy Smart energy efficiency programs, which are currently in year five, have reduced the Company's annual peak load for the east bank of Orleans Parish by an estimated 16.5 MW. For the Energy Smart programs in Algiers, annual peak load has been reduced by an estimated 1.1 MW.

The Company also accounted for the current level of behind-the-meter ("BTM") residential rooftop solar within the Company's service area when determining its long-term need, which reduced the Company's 2015 peak load by approximately 14 MW. The projected effects of Energy Smart and BTM rooftop solar on the Company's peak demand are factored into the peak load forecast, as discussed more fully below.

Q11. WOULD INCREASED INVESTMENT IN DSM OR RENEWABLE RESOURCES PROVIDE AN ECONOMIC ALTERNATIVE TO NOPS?

A. No. Regarding DSM resources, insufficient cost-effective incremental DSM programs beyond the Company's currently approved Energy Smart programs have been identified to meet the entirety of the Company's long-term needs. The Company engaged ICF International ("ICF") to conduct an analysis of the long-term DSM potential achievable in New Orleans. Based on the results of ICF's study, the Company concludes that the achievable amount of DSM in New Orleans constitutes only approximately 13% of ENO's need for long-term peaking and reserve capacity by 2019.

Renewable resources such as wind and solar photovoltaics ("PV") are intermittent because they rely on the wind and sun to produce energy, thus limiting the ability to rely on them to meet customer demand and their ability to be counted on to meet peak demand. It should also be noted that because they are intermittent, the Company cannot count a megawatt of renewable resource capacity toward meeting a megawatt of its long-term capacity needs. Thus, even if these intermittent resources could meet the Company's long-term need for incremental peaking/revenue capacity (which they cannot), the Company would need to acquire significantly more capacity than its need dictates due to their lower capacity credit. Moreover, to emphasize such capacity would not meet ENO's specific supply role need for peaking and reserve capacity.

Q12. COULD ENO DEPEND ON MISO'S CAPACITY MARKET AS AN ALTERNATIVE TO NOPS?

A. No. As I discuss further in Section III, ENO's planning assumption is that market equilibrium (where supply, including third party resources, and demand balance) in MISO South will occur around 2022. As market equilibrium approaches, capacity prices will reflect new build prices, which are significantly higher than today's capacity prices. Deferring construction of a new resource comes with considerable risk considering the long lead time necessary to gain regulatory approval of, plan, permit, and construct new resources; potential cost premiums for parts and equipment as other utilities are simultaneously shifting to modern, gas-fired resources; and expected sharply higher and more volatile capacity prices as the capacity market approaches equilibrium. Indeed, as discussed below, one need look no further than the MISO RTO, in which ENO is a Load Serving Entity ("LSE"), for a recent example of a capacity shortage leading a 20-fold increase in capacity prices from one year to the next.

Q13. WHAT OTHER CIRCUMSTANCES SUPPORT THE COMPANY'S NOPS PROPOSAL?

A. NOPS will provide a modern, cost-effective and local source of generating capacity capable of meeting ENO's long-term overall capacity needs as well as a significant portion of its peaking and reserve supply role capacity needs. NOPS will improve supply conditions in the Company's service area by providing a long-term resource capable of supporting reliable service to New Orleans during periods of peak demand and unplanned events, and it will mitigate market and supply related risks, particularly as equilibrium in the capacity market approaches. NOPS is also consistent with ENO's load shape, which supports post-System Agreement operations when ENO must plan to meet its individual resource needs without reference to the System planning perspective. NOPS will also provide a highly-reliable quick-start generation resource in New Orleans to support timely severe weather restoration efforts.

Q14. IS THE APPLICATION TO CONSTRUCT NOPS CONSISTENT WITH THE COMPANY'S FINAL 2015 INTEGRATED RESOURCE PLAN ("IRP")?

A. Yes. The Company's Final 2015 IRP was filed on February 1, 2016, in Docket No. UD-08-02.[3] Pursuant to the Council's IRP requirements, the process to develop the 2015 IRP began in June 2014 with a series of public technical conferences to solicit input from stakeholders and inform development of the IRP. The Final 2015 IRP reflects a thorough consideration, and in certain cases additional modeling and analysis, of the issues raised through the stakeholder process, and it concluded by identifying a Preferred Portfolio for meeting customers' long-term needs at the lowest reasonable cost, while considering reliability and risk. The IRP identified an overall

[3] *See* ENO Final 2015 IRP, February 1, 2016, attached here to as Exhibit SEC-7.

long-term need for capacity as well as a need for long-term peaking and reserve resources.

During development of the 2015 IRP, the Company conducted a DSM Potential Study, Generation Technology Assessment, and Portfolio Evaluation, which thoroughly evaluated a range of viable supply and demand-side resource alternatives capable of meeting those needs. The Preferred Portfolio includes cost-effective incremental DSM resources identified through the IRP process, however; the IRP established a remaining need for peaking and reserve capacity. The results of the Final 2015 IRP support the conclusion that a large G Frame CT resource such as NOPS is the lowest reasonable cost resource addition capable of meeting the Company's remaining overall long-term capacity needs (including the target planning reserve margin ("PRM") of 12%), and a substantial portion of the identified long-term peaking and reserve capacity need.

Q15. WHAT DOES YOUR TESTIMONY AND ANALYSIS OF THE COMPANY'S LONG-TERM RESOURCE NEEDS ASSUME WITH RESPECT TO THE COMPANY'S PARTICIPATION IN THE ENTERGY SYSTEM AGREEMENT ("ESA")?

A. ENO's participation, along with all of the other remaining EOCs that are participating in the ESA, will terminate on August 31, 2016. Accordingly, my testimony and analysis of ENO's long-term resource needs reflect a post-ESA planning environment. When the ESA terminates, long-term resource planning for ENO post-termination will focus on meeting the Company's long-term resource needs without reference to the System planning perspective. Importantly, as discussed by Company witness Shauna Lovorn-Marriage, the conditions upon which the Council approved early termination of the ESA included a commitment by the Company to pursue a new generating resource to be located in the Company's service area (*i.e*. Orleans Parish, Louisiana).

II. LONG-TERM RESOURCE PLANNING PROCESS AND NEEDS

A. Planning Process

Q16. WHAT IS THE PURPOSE OF THE COMPANY'S LONG-TERM RESOURCE PLANNING PROCESS?

A. The Company's planning process seeks to accomplish three broad objectives:

- To serve customers' power needs reliably;
- To do so at the lowest reasonable supply cost; and
- To mitigate the effects and the risk of production cost volatility resulting from fuel price and purchased power cost uncertainty, RTO-related charges such as congestion costs, and possible supply disruptions.

The Company's planning process seeks to design a portfolio of resources that reliably meets customer power needs at the lowest reasonable supply cost while considering risk.

Q17. PLEASE EXPLAIN THE CHARACTERISTICS THE COMPANY SEEKS TO ACHIEVE IN A LONG-TERM GENERATION CAPACITY PORTFOLIO.

A. In support of the Company's objective to provide safe and reliable service at the lowest reasonable cost while considering risk, the Company must maintain a portfolio of generation resources that includes an appropriate amount and types of capacity. With respect to the amount of capacity, the Company must maintain sufficient generating capacity to meet its peak load plus a PRM, for which the Company has established a target of 12%. With regard to the types of capacity, the Company seeks to add modern, reliable and cost-effective generating technologies consistent with its load shape. Importantly, these objectives must be considered both individually and collectively in determining an appropriate portfolio design that can achieve the planning objectives.

Q18. PLEASE ELABORATE ON THE COMPANY'S TARGET PRM.

A. For purposes of long-term planning, the Company has determined that a 12% target PRM based on installed capacity ratings and forecasted (non-coincident) firm peak load is appropriate in consideration of its long-term planning objectives and membership in MISO. A PRM is intended to provide a generation supply buffer to maintain reliable service during unplanned events, and to facilitate planned events (*e.g.*, generator or transmission maintenance). The target PRM is intended to address uncertainties such as, but not limited to, the following:

- deviation in customer load from forecast;
- unplanned outage of a major generating unit or transmission element;

- potential variability in MISO Resource Adequacy ("RA") requirements; and
- uncertainty regarding ENO's long-term resource portfolio (*e.g.*, availability of aging legacy gas and coal units sourced through PPAs).

Q19. IS THERE OTHER INDUSTRY DATA SUPPORTING THE CONCLUSION THAT A 12% PRM IS REASONABLE?

A. Yes. MISO has referenced 15% as a generally accepted reserve requirement when assessing the reliable transfer of resources inter-regionally.[4] Further, the Southwest Power Pool requires each control area to maintain a 12% capacity reserve margin, which equates to a 13.6% planning reserve margin. Notably, Indianapolis Power & Light Company ("IPL"), another MISO LSE, appears to have reached similar conclusions regarding MISO's reserve margin and has elected to use a 14% planning reserve margin applied to their non-coincident peak load for their 2014 Integrated Resource Plan, as evidenced by the following excerpt:

> <u>Planning Reserve Margin Modeling</u>
>
> IPL's minimum PRMR established by MISO for 2014 equates to an effective 14.8% reserve margin, representing an increase from 2012 (13.1%) and 2013 (14.2%). As identified above, many factors are used by MISO to establish an LSE's resource adequacy requirement. The LSE's planning reserve margin changes annually as MISO modifies its LOLE analysis and as a result of changes in its EFORd and diversity. IPL's ICAP ratings can also change annually due to the results of unit testing. For Ventyx's long term modeling purposes in this IRP, IPL identified a 14% planning reserve margin to be used consistent with IPL's summer-rated capacity. This long-term modeling number provides for targeted reserves in the range of

[4] Exhibit SEC-2, MISO Overview, NARUC Winter Meeting, February 2015 at slide 10.

> future expected MISO-determined resource needs and is consistent with the MISO specific calculations….[5]

Q20. DID JOINING MISO AFFECT THE WAY THE COMPANY CALCULATES ITS TARGET PRM?

A. Yes. Prior to joining MISO, the Company applied a 16.85% PRM based on a loss of load expectation ("LOLE") calculation for the Entergy System, which focused solely on reliability. Upon joining MISO, the Company sought to identify a PRM that provided a reasonable and stable basis for meeting long-term planning objectives, considering both reliability and the implications of participation in the larger, more diverse MISO market. Accordingly, for purposes of long-term planning the Company adopted a 12% target PRM based on installed capacity ratings and forecasted non-coincident peak load. The 12% target reflects the benefits of participating in a larger, more diverse market while recognizing the differences between MISO's annual process and the Company's long-term planning objectives.

Q21. HAS THE COMPANY PREVIOUSLY TARGETED A 12% PRM TO SUPPORT THE NEED FOR LONG-TERM RESOURCE ADDITIONS?

A. Yes, the Company's 12% target PRM is the same 12% used in establishing the need for, and the Council's subsequent approval of, the Company's share of the new Ninemile 6 CCGT unit in Council Docket UD-11-03, and the acquisition of Power Block 1 at the Union Power Station in Council Docket UD-15-01.

[5] Exhibit SEC-3, Indianapolis Power & Light Company 2014 Integrated Resource Plan, p. 45.

B. Long-Term Resource Needs

Q22. PLEASE DESCRIBE THE COMPANY'S CURRENT RESOURCE PORTFOLIO.

A. As of June 1, 2016, the Company will control approximately 1,162 MW of long-term generating capacity either through ownership or life-of-unit PPAs with affiliate Operating Companies. Table 1 below summarizes the Company's long-term capacity resources by fuel type measured in installed MW. As reflected in Table 1, roughly one-half of the capacity in the Company's existing resource portfolio is from CCGT resources. The bulk of the remaining capacity is from nuclear resources, followed by a small amount of legacy gas,[6] coal, hydro, and CT resources.[7]

Table 1

ENO Installed Capacity (2016)		
Fuel Type	**MW**	**%**
CCGT	647	56%
Nuclear	420	36%
Legacy Gas	59	5%
Coal	33	3%
Hydro	2	0%
CT	1	0%
Total	1,162	100%

[6] Legacy Gas refers to the EOC's natural gas-fired steam turbine generators originally placed in service at various points in time during the 1950s, 1960s and 1970s.

[7] Table 1 excludes Load Modifying Resources, but which are included in the Company's assessment of long-term resource needs shown in Exhibit SEC-4.

Q23. PLEASE DESCRIBE THE COMPANY'S CURRENT LOAD FORECAST.

A. In preparing the load forecast in Exhibit SEC-4, the Company utilized the methodology described in the Final 2015 IRP.[8] Through this process, a peak load forecast was developed that derives from the hourly annual twenty-year load forecast for ENO. The process accounts for existing DSM programs (*e.g.*, Energy Smart) as well as BTM residential rooftop solar PV through indirect and direct reductions to the load forecast. The resulting forecast was then adjusted for both transmission and distribution losses before incorporation into Exhibit SEC-4.

Q24. DOES THE COMPANY NEED ADDITIONAL GENERATING CAPACITY?

A. Yes. After accounting for existing and recently acquired supply and demand-side resources (which includes Energy Smart and BTM rooftop solar), the Company continues to have a need for additional long-term capacity, including a need for peaking and reserve capacity. The Company's long-term need for capacity is driven primarily by the deactivation of Michoud Units 2 and 3, which Power Block 1 helped to offset. To illustrate the Company's needs, I have compared the Company's projected peak load with its portfolio of existing resources. Exhibit SEC-4 provides a Projected Load and Capability analysis that compares the Company's overall planning requirements (based on non-coincident peak load forecast, grossed up for transmission and distribution losses, plus a target PRM of 12%) with the Company's

[8] ENO 2015 IRP at page 43.

existing long-term supply and demand-side resources that it expects to have in its portfolio during the planning horizon (based on installed capacity ratings). The results of the analysis attached as Exhibit SEC-4 provide ENO's projected needs, with and without planned resource additions (*e.g.*, NOPS).

Q25. WHAT DOES THE ANALYSIS INDICATE?

A. Projected load plus the target PRM results in a long-term capacity need that exceeds the Company's existing supply and demand-side resources, which indicate a need to deploy additional long-term resources. As shown in Exhibit SEC-4, the Company projects an overall need for approximately 134 MW of capacity by 2020 and up to 205 MW by 2030. As explained more specifically below, the Company also has a need for long-term local peaking and reserve capacity resources.

Q26. PLEASE ELABORATE ON THE TYPES OF RESOURCES THE COMPANY NEEDS.

A. In conducting long-term resource planning, the Company analyzes not only its overall capacity needs, but also its need for capacity that serves specific supply roles, such as: base load, load following, peaking, and reserve. Having an appropriate amount of capacity suitable to serve each of these supply roles allows the Company to reliably and cost-effectively serve the time-varying level of customer load.

Supply role requirements are considered as general guidelines for portfolio planning purposes and do not necessarily address other planning criteria (*e.g.*, locational considerations). As illustrated in Figure 1 below, the Company defines its base load requirement as the minimum level of load that is served 85% of the hours in a year. Next, the load following requirement is defined as the levels of load that exceed base load but are less than load levels experienced in the highest 15% of the hours of the year (*i.e.*, core load-following and seasonal load-following). The Company's peaking requirement is defined as the level of load that is served in the highest 15% of the hours of the year. Finally, the PRM target is 12% of the peak load and, as described earlier, helps to maintain reliable service over a range of planned and unplanned circumstances.

Figure 1 Highly Sensitive Protected Materials

[redacted]

Each supply resource has its own unique cost and performance characteristics that allow it to be functionally and economically suited to serve a given supply role. Generally, base load resources typically cost more to construct per MW, but operate with relatively low variable cost and, because the resource is expected to operate in most hours at high output levels, the total supply cost is relatively low on a $/MWh basis. Conversely, a peaking or reserve unit is expected to operate at low utilization levels and higher variable costs, but typically has a relatively low capital cost and, therefore, is typically the most economical alternative when utilized in a peaking role. Load following units have moderate capital cost and variable cost.

In order to reliably meet customers' needs at the lowest reasonable cost, the Company must maintain a portfolio of long-term resources that includes an appropriate amount and types of capacity. At this time, the Company has a need for long-term resources, including resources capable of operating in a peaking and reserve role. Table 2 provides the Company's projected capacity surplus or (deficit) overall and across supply role.[9]

Table 2

(MW)[10]	2020 Need	2020 Resources	2020 Surplus/ (Deficit)	2030 Need	2030 Resources	2030 Surplus/ (Deficit)
Base Load	554	453	(101)	572	427	(145)
Load Following	338	682	344	342	665	323
Peaking & Reserve	417	40	(377)	422	39	(383)
Total	1,309	1,175	(134)	1,336	1,131	(205)

As shown in Table 2, the Company projects the need for approximately 377 MW of peaking and reserve resources by 2020, which need is expected to grow to

[9] The Company's Load Modifying Resources are included in the supply role analysis as Reserve capacity, as shown in Exhibit SEC-4.

[10] Figures may not foot as compared to Exhibit SEC-4 due to rounding.

approximately 383 MW near the end of the planning horizon (2030) absent the addition of new resources. Even absent growth in the Company's peak load, the need for peaking and reserve resources driven by the deactivation of Michoud Units 2 and 3 is substantial and exceeds the amount of capacity that would be obtained through the addition of NOPS.

Q27. HOW WILL THE COMPANY MEET ITS LONG-TERM NEED FOR PEAKING AND RESERVE RESOURCES PRIOR TO THE IN-SERVICE DATE FOR NOPS?

A. Based on my assessment of the current and previous MISO Planning Resource Auctions ("PRA") for MISO South, as well as the 2015 OMS Survey, it is reasonable to expect that excess capacity will be available in the PRA through the end the decade. Based on that expectation, the Company plans to meet near-term peaking and reserve capacity and energy needs through the MISO markets until NOPS is constructed.

Q28. HOW DO YOU CONCLUDE THAT CT RESOURCES SUCH AS NOPS ARE BEST SUITED TO MEET THE COMPANY'S LONG-TERM PEAKING AND RESERVE CAPACITY NEEDS?

A. CT resources such as NOPS are the preferred technology to meet current and projected long-term peaking and reserve capacity needs due to their low installed cost and operational flexibility. Because peaking and reserve capacity resources are not expected to operate for extended periods of time, their installed cost is more relevant than operating costs. In addition, during periods of peak demand, generating resources must be able to respond quickly to changing conditions on the electric system in order to maintain reliability by starting on short notice and responding to dispatch signals to quickly ramp up or down. Consistent with the Company's planning objectives, CT resources such as NOPS provide the lowest reasonable cost technology capable of meeting peaking and reserve capacity needs while considering market and supply risks. In Section III below, I discuss in more detail why CT resources such as NOPS are better suited than prospective alternatives to meet the Company's long-term peaking and reserve capacity needs.

Q29. YOU IDENTIFIED A LONG-TERM NEED FOR PEAKING AND RESERVE CAPACITY THAT EXCEEDS THE CAPACITY OF NOPS. PLEASE EXPLAIN WHY THE COMPANY IS NOT PROPOSING ADDITIONAL LONG-TERM RESOURCE ADDITIONS BEYOND NOPS TO MEET THAT NEED.

A. With the addition of NOPS, the Company is projected to meet its overall long-term capacity need as well as a substantial portion of the projected peaking and reserve capacity need. Table 3 provides the effect of NOPS on the Company's long-term capacity needs following the projected in-service date, which reflects a slight overall surplus of capacity through 2030 and a persistent peaking and reserve capacity deficit. When determining how best to meet long-term needs, the Company must consider a range of factors. NOPS is a significant incremental resource addition that will help meet a substantial portion of the Company's long-term need for local peaking and reserve resources. It will also meet the Company's overall long-term capacity needs, including the target PRM.

While the supply role analysis indicates the need for additional peaking and reserve capacity, it also indicates a surplus of load-following capacity. The surplus load-following capacity is primarily driven by the acquisition of Power Block 1, which at current and projected gas prices can also help meet the projected need for baseload resources. In contrast, it would not be appropriate to rely on the surplus load-following capacity associated with Power Block 1 to meet the identified peaking and reserve needs because Power Block 1 is already included in ENO's resource mix and contributes to meeting other supply role needs, and Power Block 1 is outside the Company's service area and does not address the need for local area peaking and reserve capacity to support long-term reliability within the Company's service area. Thus, the results of the supply role analysis must be taken into consideration along with other factors, including the Company's overall long-term needs, market dynamics, and locational considerations. The addition of NOPS strikes the appropriate balance among these considerations. Further, peaking and reserve capacity needs not met by NOPS provides an opportunity to pursue cost-effective DSM, which I discuss in Section III below.

Table 3

	2020			2030		
(MW)[11]	**Need**	**Resources w/ NOPS**	**Surplus/ (Deficit)**	**Need**	**Resources w/ NOPS**	**Surplus/ (Deficit)**
Base Load	554	453	(101)	572	427	(145)
Load Following	338	682	344	342	665	323
Peaking &	417	266	(151)	422	265	(157)

11 Figures may not foot as compared to Exhibit SEC-4 due to rounding.

Reserve						
Total	1,309	1,401	92	1,336	1,357	21

Q30. PLEASE ELABORATE ON THE COMPANY'S NEED FOR LOCAL AREA GENERATING CAPACITY.

A. Prior to deactivation, Michoud Units 2 and 3 provided a significant amount of local area capacity because both units were within ENO's service area (*i.e.* Orleans Parish), which is part of the supply-constrained Downstream of Gypsy ("DSG") load pocket. Because the Company's service area is located in a load pocket, the planning process must factor in the ability to maintain reliability during unplanned events like hurricanes, the forced outage of a major transmission element(s) relied upon to import generation to the region, and the forced outage of a large generator(s) within the load pocket that supports local area reliability (*e.g.*, Ninemile). Absent the addition of NOPS, ENO will not have any generating capacity within its service area, and it must rely on other generation within the load pocket to maintain local area reliability.

While ENO does receive a long-term allocation of the three remaining generating resources within the load pocket through life-of-unit power purchase agreements (*i.e.*, Ninemile units 4, 5 and 6), Ninemile units 4 and 5 are over 40 years old, and all three units are located outside of the Company's service area. Moreover, ENO's existing portfolio relies heavily on resources external to its service area to serve the energy and capacity needs of the Company. Table 4 provides a breakdown of ENO's existing portfolio of generating capacity based on proximity to the

Company's service area and the load pocket more generally.[12] The addition of NOPS to the Company's portfolio would constitute the only generating capacity within Orleans Parish, and will accordingly reduce the reliance on the Ninemile generating facility to maintain local area reliability within Orleans Parish.

Table 4 Highly Sensitive Protected Materials

[redacted]

Q31. PLEASE ELABORATE ON THE RELIABILITY BENEFITS OF LOCAL GENERATION.

A. As explained by Mr. Charles Long, the addition of local generation will help prevent stability problems that are caused by disturbances and faults, supply dynamic reactive power, and dynamically regulate voltage. New local generation will also reduce the Company's reliance on transmission import capability, which is limited by the interface of the transmission elements that connect the load pocket with the rest of the transmission network.

Q32. ARE THERE ADDITIONAL BENEFITS OF LOCAL GENERATION?

A. Yes. Local generation provides the following additional benefits:

- Improves Economics – Local generation reduces transmission losses by locating the source of electricity near the load to be served. Transmission

[12] As of June 1, 2016.

losses can increase during periods of peak demand, providing further support for siting peaking resources near the peak load to be served.

- Mitigates Market Risks – Local generation will mitigate transmission congestion price risk and supply power that can be dispatched at a known heat rate, helping to limit volatility of, and customer's exposure to, locational marginal prices ("LMPs"), which exposure is typically greatest during periods of peak demand. In other words, when there is congestion on the transmission system between generating resources and load, LMPs typically increase. This not only increases the cost of load purchases from MISO, but also increases payments from MISO to generators in the affected area. If ENO faces these higher LMPs in the ENO load zone, the increased LMP revenues received by NOPS act as a hedge to offset the increased cost of load purchases from MISO.
- Reduced Reliance on Transmission Imports – As discussed by Mr. Charles Long, locating new resources near the load to be served will reduce reliance on transmission imports, which in turn can reduce the need for future transmission upgrades necessary to maintain reliability and mitigate congestion.
- Long-term Strategic Benefits – NOPS will provide a modern, cost-effective local source of peaking and reserve capacity that will reduce the Company's reliance on the Ninemile generating plant to maintain reliability in Orleans Parish.

Q33. DO LOCAL RESOURCES PROVIDE BENEFITS DURING STORM RESTORATION?

A. Yes. Having additional local generation will reduce the Company's reliance on transmission assets that may be more likely to be out of service immediately following a severe weather event (*e.g.*, hurricane). For example, as discussed in more detail by Mr. Charles Long, in September 2008, Hurricane Gustav affected all of the transmission lines serving the region, which included the Company's service area, leaving the region "islanded" from the rest of the interconnected transmission grid and, thus, completely reliant on local generation at a critical time. As noted in Table 4 above, the Company relies exclusively on transmission to deliver external resources to its service area, which highlights the need for local generating capacity in the event of a major disruption to the transmission system as a result of a severe weather event such as a hurricane. In other words, having local generation is critical to restoring and maintaining power to customers in New Orleans.

III. <u>PROSPECTIVE ALTERNATIVES</u>

Q34. IS NOPS CONSISTENT WITH THE SUPPLY ROLE NEEDS OF THE COMPANY?

A. Yes. CT resources, such as NOPS, are technologically suited for serving peaking and reserve roles. As discussed by Company witness Jonathan E. Long, NOPS is a modern CT unit capable of being started quickly and ramped to full load within minutes. This capability will support local area reliability and could help facilitate the integration of renewable resources in or near the Company's service area by providing a quick start resource capable of coming online and ramping quickly to address the intermittency associated with renewables. Further, because of the limited expected capacity factor for peaking and reserve resources, CT technology is economically suited to serve in these roles across a range of assumptions regarding key uncertainties (*e.g.*, fuel prices and emissions costs). Consequently, CT resources such as NOPS support the Company's planning objectives and are consistent with supply role needs.

Q35. COULD THE COMPANY'S PEAKING AND RESERVE CAPACITY NEEDS BE SATISFIED WITH RENEWABLE RESOURCES?

A. No. Renewable resources such as wind and solar PV are intermittent because they rely on the wind and sun to produce energy, thus limiting the ability to rely on them to meet customer demand. Moreover, the generating capacity of renewables such as wind and solar PV are a function of the amount of wind and sunlight available at a given time, further limiting their ability to be counted on to meet peak demands. As a result, renewables must be supported by dispatchable resources such as CTs to ensure sufficient resources are available to ramp up and produce replacement energy when the wind is either not blowing or blowing less than projected, and similarly when cloud cover or unexpected weather limits the output of solar PV. Finally, because wind and solar are intermittent, even if it were cost-effective to acquire an amount sufficient to meet the Company's long-term capacity needs, it would not eliminate the need for quick-start and fast ramping dispatchable resources such as NOPS.

Q36. DOES THIS MEAN THAT INTERMITTENT RESOURCES SUCH AS SOLAR PV AND WIND HAVE NO PLACE IN ENO'S SUPPLY PORTFOLIO?

A. Not at all. To the extent there are cost-effective sources of renewable energy available to the Company, they could provide benefits to customers in the form of increased diversity of supply and other environmental attributes. As identified in the Company's Action Plan supporting the Final 2015 IRP,[13] ENO is undertaking an RFP to determine whether there are cost-effective renewable resources available.[14]

Q37. DOES THE INTERMITTENT NATURE OF RENEWABLES SUCH AS SOLAR PV AND WIND AFFECT THE EXTENT TO WHICH THEY CAN BE RELIED UPON TO MEET LONG-TERM CAPACITY NEEDS?

A. Yes. Even if the cost of wind and solar PV were comparable in cost to conventional alternatives, it is reasonable to expect that the total cost to acquire sufficient renewable capacity to meet ENO's overall long-term needs would exceed the cost of conventional alternatives because the Company cannot count a megawatt of renewable resource capacity toward meeting a megawatt of its long-term capacity needs, precisely because both technologies are intermittent.

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13 ENO 2015 IRP at page 84.

14 On May 6, 2016 ESI issued a draft request for proposals for renewable generation resources. The RFP will facilitate a market test of the extent, and cost of, renewable resources available to provide benefits in excess of cost to the Company's customers. More information on the Draft RFP can be found on the ESI RFP Website located at: https://spofossil.entergy.com/ENTRFP/SEND/2016ENOIRenewableRFP/Index.htm.

Q38. HOW DOES MISO ACCOUNT FOR THE INTERMITTENCY OF RENEWABLE RESOURCES THROUGH THE RESOURCE ADEQUACY PROCESS?

A. Because wind and solar are intermittent, MISO grants those resources less capacity credit in the RA process. For the 2016/2017 Planning Year, MISO granted a 15.6%[15] capacity credit to wind resources and 50%[16] capacity credit to solar PV resources (during the first year of solar PV operation subject to verification with operational data). Thus, reliance on renewable resources alone to meet MISO's RA requirements would require the Company to invest in significantly more renewable resource capacity than its capacity need would otherwise support.

Q39. WILL NOPS PRECLUDE THE COMPANY'S ABILITY TO INCORPORATE RENEWABLE RESOURCES INTO FUTURE RESOURCE PLANS?

A. No. As indicated in Table 1, the Company's existing portfolio includes aging legacy gas and coal generating resources. As those units are deactivated based on their own economic merits, there will be room in the portfolio for new resource additions, creating opportunity for cost-effective renewable energy resources such as wind and solar PV. Moreover, because the cost and performance of solar PV (and to a lesser extent wind) is expected to continue to improve, deferring the addition of those resources could increase the benefits to customers.

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[15] https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf.

[16] https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2015/20150930/20150930%20LOLEWG-SAWG%20Joint%20Meeting%20Item%2003%20Solar%20Capacity%20Credit.pdf.

Q40. CAN THE COMPANY'S PEAKING AND RESERVE RESOURCE NEEDS BE MET THROUGH UTILITY-SPONSORED DSM PROGRAMS?

No. Insufficient achievable DSM resources are available to meet the Company's peak capacity needs. The need for peaking capacity identified in Table 2 is driven primarily by the deactivation of Michoud Units 2 and 3, which need is expected to persist absent the addition of new peaking resources. DSM programs offer opportunities to offset some level of long-term capacity needs, but not enough to meet the entirety of ENO's long-term needs.

Moreover, DSM programs capable of reducing peak capacity requirements must be designed and properly administered through the development of detailed implementation plans that involve customer education and outreach in order to facilitate participation, and they require that appropriate cost recovery and incentive mechanisms be approved by the Council, all of which extend the timeframe for achieving desired results. Moreover, industry experience has shown that customer subscription to demand response programs must significantly exceed the target demand reduction (*i.e.*, oversubscribe participants to the program) in order to achieve the desired results due in large part to the inability to pass penalties on to the customer when they override the request to curtail. This highlights the uncertainty and additional cost associated with relying on demand response programs to meet peaking capacity needs.

Additionally, as part of the ENO 2015 IRP, the Company engaged ICF to conduct an analysis of the long-term DSM potential achievable in New Orleans. ICF concluded that cost-effective DSM could potentially avoid a cumulative 112 MW of peak demand by the end of the 20-year study period.[17] Importantly, it takes time to design programs, develop marketing materials, and ramp up spending, thus limiting the amount of DSM potential that can be achieved in the near-term. For example, ICF estimates that by 2019, approximately 49 MW of cumulative peak demand could be avoided through cost-effective DSM programs. As shown in Table 2 above, the Company needs approximately 377 MW of peaking and reserve capacity by 2020, which far exceeds the capacity of the cost-effective DSM potential identified by ICF in the near-term. Moreover, the Company's long-term peaking and reserve capacity needs exceed the capacity associated with NOPS, thus leaving ample room to pursue cost-effective DSM potential over the planning horizon.

Q41. WOULD IT BE PRUDENT TO RELY ON THE MISO ANNUAL PLANNING RESOURCE AUCTION TO MEET LONG-TERM RESOURCE NEEDS?

A. No. While the MISO PRA provides a short-term option to meet customers' needs, over-reliance on the short-term market in lieu of long-term resources – especially at a time when market conditions are expected to begin tightening toward equilibrium – involves greater risk compared to a long-term resource such as NOPS, as explained below. I note that, by reliance, I mean a circumstance in which the Company does not have enough long-term owned or controlled capacity sufficient to meet its long-

[17] In its conclusions, ICF noted that DSM potential studies are forecasts, and thus contain a margin of error and uncertainty with respect to the ability to achieve estimated potential.

term needs, and it seeks to satisfy that deficit with short-term capacity purchased from others in the MISO auction (which purchases are valid only for one year).

Q42. WHEN ARE MARKET CONDITIONS EXPECTED TO TIGHTEN?

A. While the exact timing is unknown, based on an assessment of capacity supply, including third party resources that could be available to the Company through PPAs, and peak demand in the MISO South region, the Company currently projects that the MISO capacity market will reach supply/demand equilibrium in the year 2022. In addition, the 2015 OMS MISO Survey produced by MISO in July 2015 indicates that MISO believes market equilibrium could be reached in the 2020 timeframe across the entire MISO footprint.

Q43. PLEASE EXPLAIN THE CIRCUMSTANCES THAT INFLUENCE MARKET EQUILIBRIUM.

A. Market conditions in MISO South and the entire MISO market are driven by the demand for, and supply of, capacity, which is expected to change over time. As load grows and/or generating resources deactivate, which is the situation today, there will be a time when demand equals or exceeds the available generating capacity, absent the construction of new generation resources. Importantly, the balance of supply and demand in the MISO annual PRA should not be extrapolated to infer the balance of demand for and supply of long-term generating capacity, as the auction is limited to one planning year ahead. The future availability of long-term capacity is determined by a variety of factors that are independent of MISO's annual RA process.

Q44. WHAT ARE THE CONSEQUENCES OF REACHING MARKET EQUILIBRIUM?

A. Equilibrium is the point at which supply, including third-party resources, and demand, including appropriate planning reserves, are in balance. Put differently, equilibrium is the point at which the price signal for capacity approaches the cost of new build. Thus, as equilibrium approaches, the price for capacity is expected to increase significantly from current levels. Furthermore, as recent industry trends have shown, current and projected prices for natural gas coupled with increasing pressures to move away from carbon-intense fuel sources are leading to an increase in the demand for lower carbon alternatives such as modern natural gas-fired CT technologies. As demand for these types of resources increase, the cost for labor and materials necessary to construct and install new CT resources would be expected to increase. Deferring deployment of new CT resources nearer to, or even after, market equilibrium will expose customers to increased risk of significantly higher costs due to the labor and equipment premiums and long lead times that would be required for those resources. Moving forward with deployment of NOPS now will mitigate customers' exposure to higher capacity prices as equilibrium approaches as well as the potential cost premium and longer lead times that may be required for new CT resources as equilibrium occurs.

Q45. CAN YOU PROVIDE AN EXAMPLE OF THE RISK ASSOCIATED WITH THE PRICE FOR CAPACITY INCREASING AS THE MARKET APPROACHES EQUILIBRIUM?

A. Yes. Earlier this year, MISO published the results of the PRA for the 2016/2017 Planning Year, which began June 1, 2016. MISO reported that the Auction Clearing Price ("ACP") for Local Resource Zones ("LRZ") 2 through 7 (*i.e.*, majority of MISO North) was $72/MW-day. In sharp contrast, the ACP for LRZ 2 through 3 and 5 through 7 for the prior 2015/2016 Planning Year was $3.48/MW-day, representing over a 20-fold increase in the ACP from the 2015/2016 to 2016/2017 Planning Year. MISO explained that the increase was driven in part by a 4,500 MW decline in capacity bid into the PRA in MISO North. This highlights the uncertainty associated with relying on the MISO annual PRA to meet long-term resource needs, which exposes customers to greater risk.

Q46. COULD THE RESOURCE NEEDS OF ENO BE MET SOLELY THROUGH TRANSMISSION UPGRADES?

A. No. As explained above, the MISO capacity market is tightening and is expected to reach equilibrium early in the next decade, if not sooner. Upon reaching equilibrium, no amount of transmission investment will be able to address the resource needs of the Company as there will be no excess capacity to serve load.

In addition to mitigating market risks, as discussed by Company witness Charles Long, there are important reliability and economic factors associated with locating generating resources close to load in order to reduce reliance on transmission where possible and improve reactive power capability and the ability to dynamically regulate voltage. Moreover, as discussed by Mr. Long, there are voltage and local reliability ("VLR") needs in the region that includes ENO's load zone, as determined by MISO, that are most economically and effectively addressed through incremental local area generating capacity. As Mr. Long explains, NOPS will likely have a VLR role in DSG, and if the unit is not constructed, significant large-scale transmission projects would be necessary to maintain reliability over the long-term, ten-year planning horizon. As discussed above, meeting a portion of the Company's long-term needs with local area generating resources will support longer-term reliable operations by ensuring adequate local generating resources are available to facilitate planned generator and transmission outages, mitigate risks associated with unplanned outages, and reduce reliance on transmission imports to serve ENO's load. In addition, local generation will enhance ENO's ability to restore service in the aftermath of a severe weather event, including a hurricane. As indicated in Table 4, the Company already relies heavily on resources external to both its service area and the load pocket, which supports the addition of NOPS to mitigate these and other market and supply related risks.

IV. TECHNOLOGY AND SITE SELECTION

A. Selection of the CT Technology

Q47. HOW DID THE COMPANY DETERMINE THE APPROPRIATE CT TECHNOLOGY FOR NOPS?

A. A technology assessment was conducted in 2015 that considered seven different CT technologies: four large frame CTs, two aero derivative CTs, and one internal combustion engine ("ICE"). The analysis included an assessment of qualitative and quantitative factors consistent with ENO's peaking capacity needs. The results of the analysis support the selection of NOPS as the preferred CT technology, and the analysis is included as Exhibit SEC-5 to my testimony.

Q48. WHAT SPECIFIC CONCLUSIONS WERE DRAWN FROM THE 2015 ASSESSMENT THAT SUPPORTS THE SELECTION OF NOPS AS THE PREFERRED CT TECHNOLOGY?

A. The 2015 assessment evaluated the alternative technologies against a range of factors, including fixed and total supply cost, operational flexibility, ENO's planning needs, and gas pressure requirements. The results showed that selection of the Mitsubishi Hitachi Power Systems America ("MHPSA") 501 GAC large frame CT best fit ENO's planning needs because it provides the highest capacity rating and lowest total supply cost of all seven technologies. In addition, it has a comparable heat rate and competitive ramping rates to provide operational flexibility.

Q49. WERE THERE ANY ADDITIONAL CONCLUSIONS IMPORTANT TO THE SELECTION OF NOPS?

A. Yes. The economic assessment examined the supply costs of each of the seven alternatives based on an assumed 30-year operating life. As shown in Exhibit SEC-5, even though the MHPSA 501 GAC provides the most capacity of all the alternative machines analyzed, it ranked the lowest in terms of total supply costs. It was followed by the three other large frame CTs, then the two aero derivatives, and finally the ICE. Thus, although smaller-sized units were considered, the larger MHPSA 501 GAC proved to be the most economic solution.

Q50. IS THE SELECTION OF THE MHPSA 501 GAC CONSISTENT WITH THE TECHNOLOGY ASSESSMENT IN THE 2015 IRP?

A. Yes. The Generation Technology Assessment in the 2015 IRP evaluated a range of supply-side resource technologies, including a range of CT technologies and sizes. The CT technologies evaluated included a large aero-derivative CT as well as a small and large Frame CT. The assumptions for each technology were meant to be representative of the cost and performance for each *class* of CT and not specific to a particular manufacturer since there are multiple manufacturers that offer some or all of the technologies evaluated.

Consistent with the Company's identified long-term peaking and reserve capacity needs, the Company completed the analysis summarized in Exhibit SEC-5 to inform the selection of a CT technology that considers the cost and performance of the particular manufacturers' product offerings. That analysis confirms the conclusion reached in the Draft and Final 2015 IRP that a large frame CT is the preferred CT technology to meet the Company's long-term peaking and reserve capacity needs. Moreover, the analysis in Exhibit SEC-5 provides the rationale for the particular CT chosen for NOPS – the MHPSA 501 GAC – over the other alternatives, including other large Frame CTs.

Q51. HAVE YOU CONDUCTED A MORE RECENT TECHNOLOGY ASSESSMENT?

A. Yes. In March 2016, the Company conducted an assessment using the best available information for the MHPSA 501 GAC as well as two alternative CTs. That assessment included a screening level analysis comparing the MHPSA 501 GAC and GE 7FA.05 large frame CTs and the smaller GE LMS100 aero derivative CT. That screening level analysis is summarized in Figure 2 below, and confirms the selection of the MHPSA 501 GAC over the GE 7FA.05 and GE LMS100 CTs.

Figure 2 Highly Sensitive Protected Materials

[redacted]

Q52. WAS A MORE DETAILED ECONOMIC EVALUATION CONDUCTED AS PART OF THE 2016 ASSESSMENT?

Yes. As a part of the 2016 assessment, the Company evaluated the total supply cost of the MHPSA 501 GAC and the smaller GE LMS100 using the AURORA production cost model to determine if the economics of deploying a single GE LMS100 in 2019 and deferring the addition of a second GE LMS100 until a later date could result in a lower total supply cost as compared to deploying the larger MHPSA 501 GAC in 2019.

Q53. DID THAT ECONOMIC ANALYSIS CONFIRM THE SELECTION OF MHPSA 501 GAC FOR NOPS?

A. Yes. Figure 3 summarizes the results of the total supply cost component of the 2016 economic analysis comparing the MHPSA 501 GAC in 2019 (*i.e.*, Alternative 1) to deploying the first GE LMS100 in 2019 and then a second GE LMS100 in each year of the analysis (*i.e.*, Alternative 2). As shown in Figure 3, Alternative 2 is inferior because the total supply costs exceed that of Alternative 1 in each year regardless of how long the addition of the second GE LMS100 is deferred.

Figure 3 Highly Sensitive Protected Materials

[redacted]

Q54. WERE OTHER FACTORS CONSIDERED IN THE 2016 ASSESSMENT THAT SUPPORTS ALTERNATIVE 1?

A. Yes. As shown in Exhibit SEC-6, in addition to the evaluation of total supply cost, the Company also considered qualitative factors in determining the preferred alternative, including locational considerations, transmission upgrades, market risks, local area reliability, technology risks, and financing/capital requirements. The scoring on the qualitative assessment supports the selection of the MHPSA 501 GAC over the GE LMS100.

Q55. PLEASE SUMMARIZE THE RESULTS OF THE 2016 ASSESSMENT.

A. Deploying the MHPSA 501 GAC in 2019 results in the lowest total supply costs and best meets ENO's long-term resource needs and stated planning objectives of cost, reliability, and risk mitigation:

- the MHPSA 501 GAC more closely aligns with ENO's need for long-term peaking and reserve resources and will provide additional local area generation in support of longer-term reliable operations within the Company's service area, while mitigating market and supply related risks;
- the MHPSA 501 GAC provides better overall economics through a lower fixed cost commitment on a total dollar investment, and $/kW installed cost, as compared to deploying one GE LMS100 in 2019 and deferring the addition of a second GE LMS100 until a later date;

- the MHPSA 501 GAC will mitigate risks associated with the increasing cost of capacity, including construction and material costs, through a known and measurable upfront investment to meet long-term needs;
- the relative economics of the MHPSA 501 GAC are not dependent on the market for capacity prices in MISO; and
- deploying the MHPSA 501 GAC will allow the Company to leverage a growing fleet with operational experience and efficiencies associated with operating and maintenance costs.

B. Site Selection

Q56. HOW WAS THE SITE SELECTED FOR THIS PROJECT?

A. Based on the local considerations discussed above, and in accordance with the Council's directive in Resolution R-15-524, which directed the Company to use "reasonable diligent efforts" to pursue development of a peaking resource in the City following termination of the ESA, the site selection process involved identification of potential locations for the development of new generation in Orleans Parish. Considerations included factors related to fuel supply, transmission, existing infrastructure, site suitability, and environmental regulations.

Q57. WHAT ALTERNATIVE SITES WERE CONSIDERED FOR THE LOCATION OF NOPS?

A. As shown in Exhibit SEC-5, two potential sites in Orleans Parish were evaluated for new unit suitability: A.B. Paterson and Michoud. A.B. Paterson was eliminated due to limited fuel and other infrastructure. Michoud is located closer to three major gas pipelines, and it has existing office building infrastructure as well as available bays in the high-voltage switchyard for interconnection to the transmission system. In addition, the Michoud substation is more strongly interconnected to the Company's service area and the load pocket more broadly, via multiple lines at both 230 kV and 115 kV voltages, which enables a resource at the Michoud site to provide more support to local reliability versus a resource interconnected at the A.B. Patterson site.

C. Project Approval

Q58. DID THE ENO OPERATING COMMITTEE APPROVE THE CONSTRUCTION OF NOPS?

A. Yes. Based on the analysis presented in Exhibit SEC-6, the ENO Operating Committee approved NOPS on March 31, 2016.

V. CONCLUSION

Q59. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's long-term resource planning process indicates a need for capacity, including additional peaking and reserve capacity. Local considerations indicate that it would be most beneficial to customers to locate this new capacity in Orleans Parish, particularly considering the deactivation of Michoud Units 2 and 3. Locating the unit in Orleans Parish also provides reliability benefits by being close to the load it serves. Finally, the construction of additional long-term generation in the Company's service area, such as NOPS, will mitigate risk to the Company's customers associated with

MISO capacity and energy market price volatility, enhance the Company's ability to restore service following severe weather events, and comply with the Council's directive in the System Agreement settlement to pursue locating a peaking resource in Orleans Parish.

Q60. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF [redacted]RLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **SETH CUREINGTON**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Seth C ington

SWORN TO AND UBSCRIBED BEFORE ME
TH

OTARY PUBLI

My commission expires:

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of
My Commission is issued for Life

SETH E. CUREINGTON

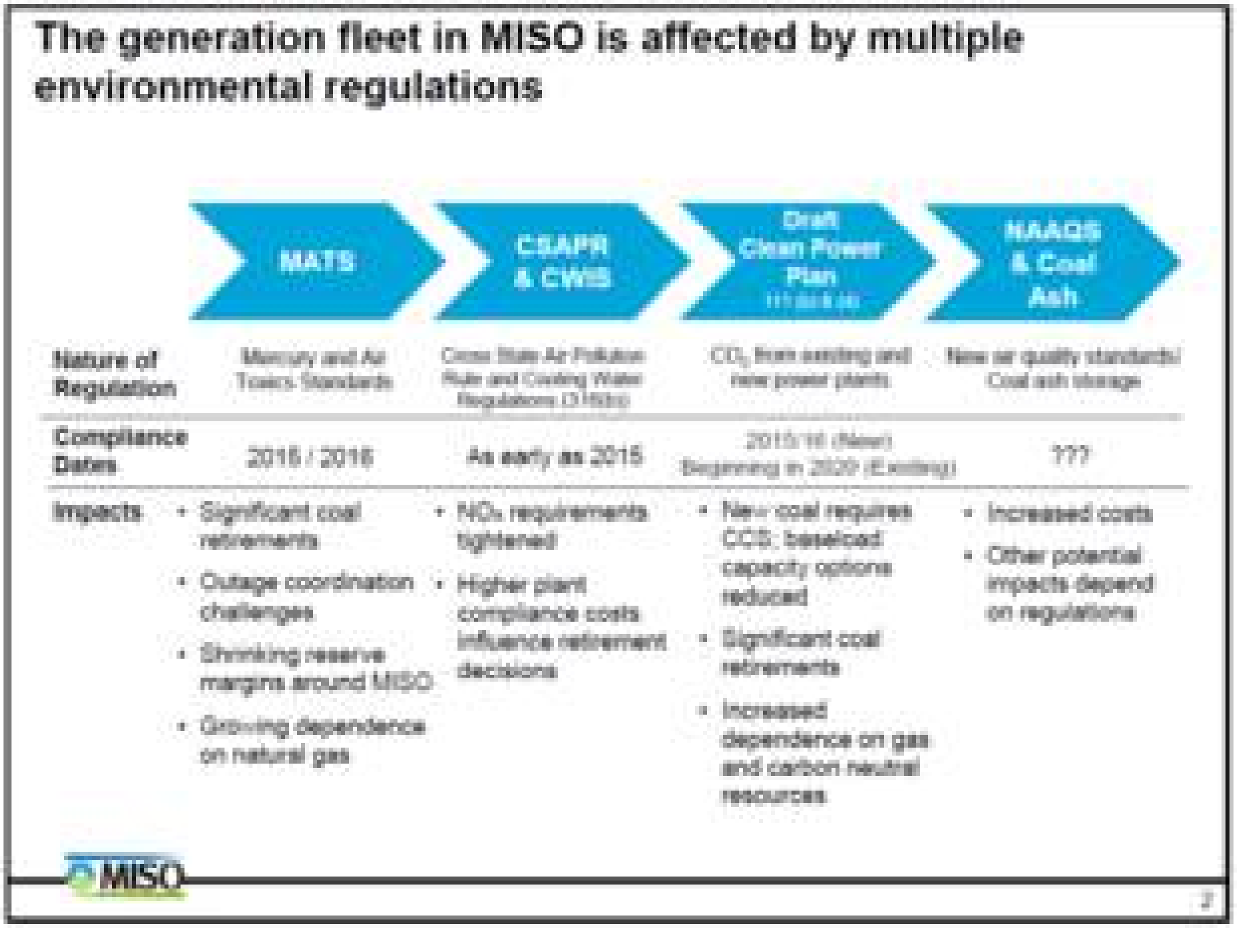
PRIOR TESTIMONY BEFORE COUNCIL FOR THE CITY OF NEW ORLEANS

Docket	Date	On Behalf Of	Subject
UD-14-02	October 2014	Entergy New Orleans, Inc.	Algiers Transfer
UD-15-01	February 2015	Entergy New Orleans, Inc.	Union PPA
UD-15-01	August 2015	Entergy New Orleans, Inc.	Union Power Block 1


MISO
MISO Overview
NARUC Winter Meeting
February 2015

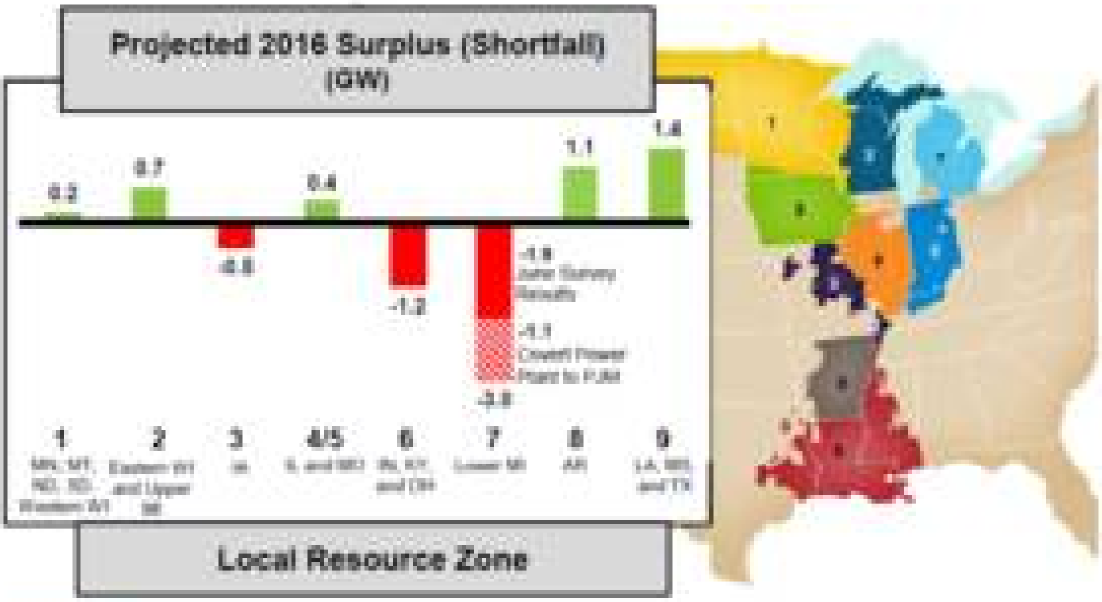
MISO focus is broad in response to the nation's changing energy landscape

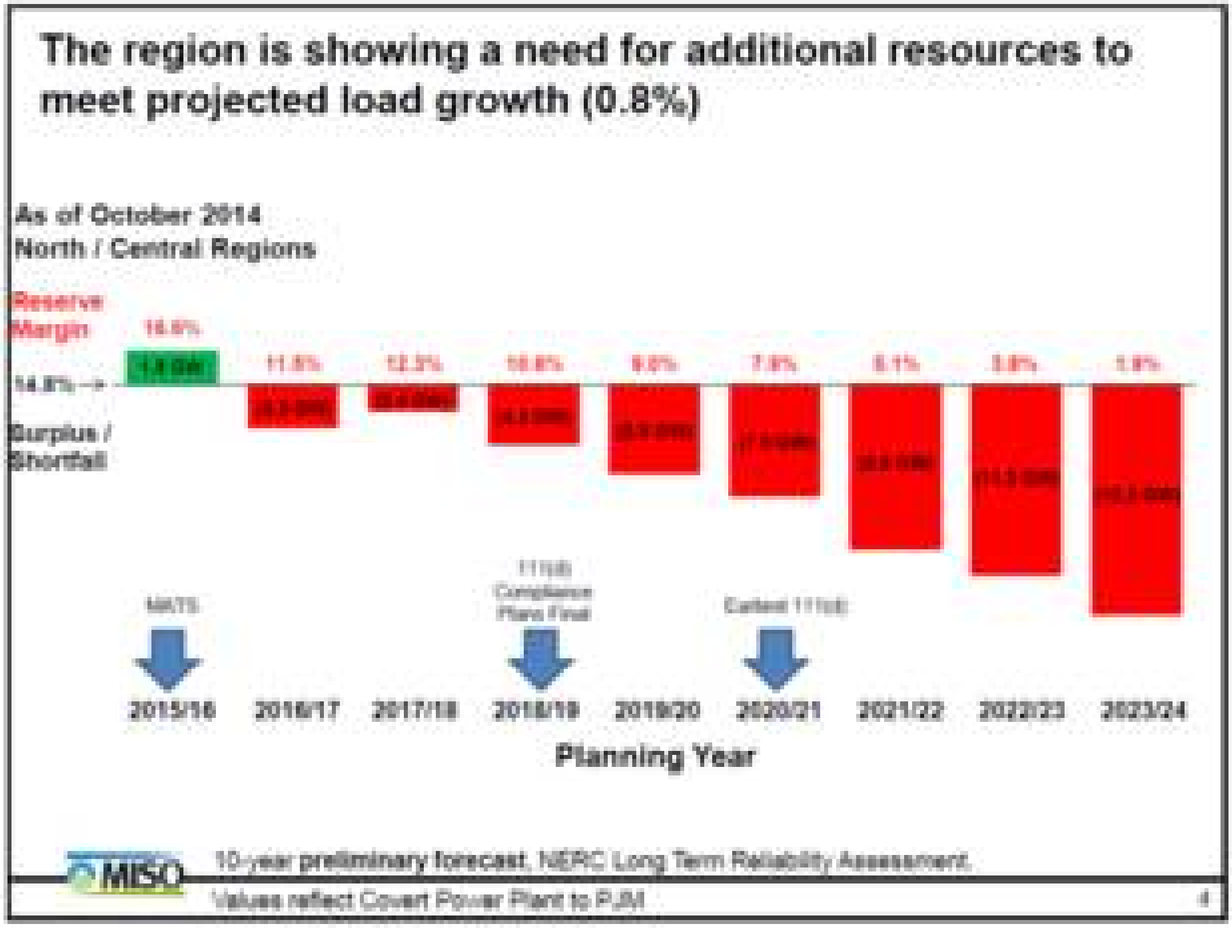
- **Environmental Regulations –** managing transition to Mercury and Air Toxics Standards (MATS) and preparing for Clean Power Plan (111(d))
- **Resource Adequacy** – efforts being taken to ensure adequacy throughout entire year and accommodate a changing portfolio
- **MISO Processes and Procedures –** review / revise to align as industry continues to evolve
- **Seams Management and Optimization** – enhancing reliable movement of resources to minimize cost to end user

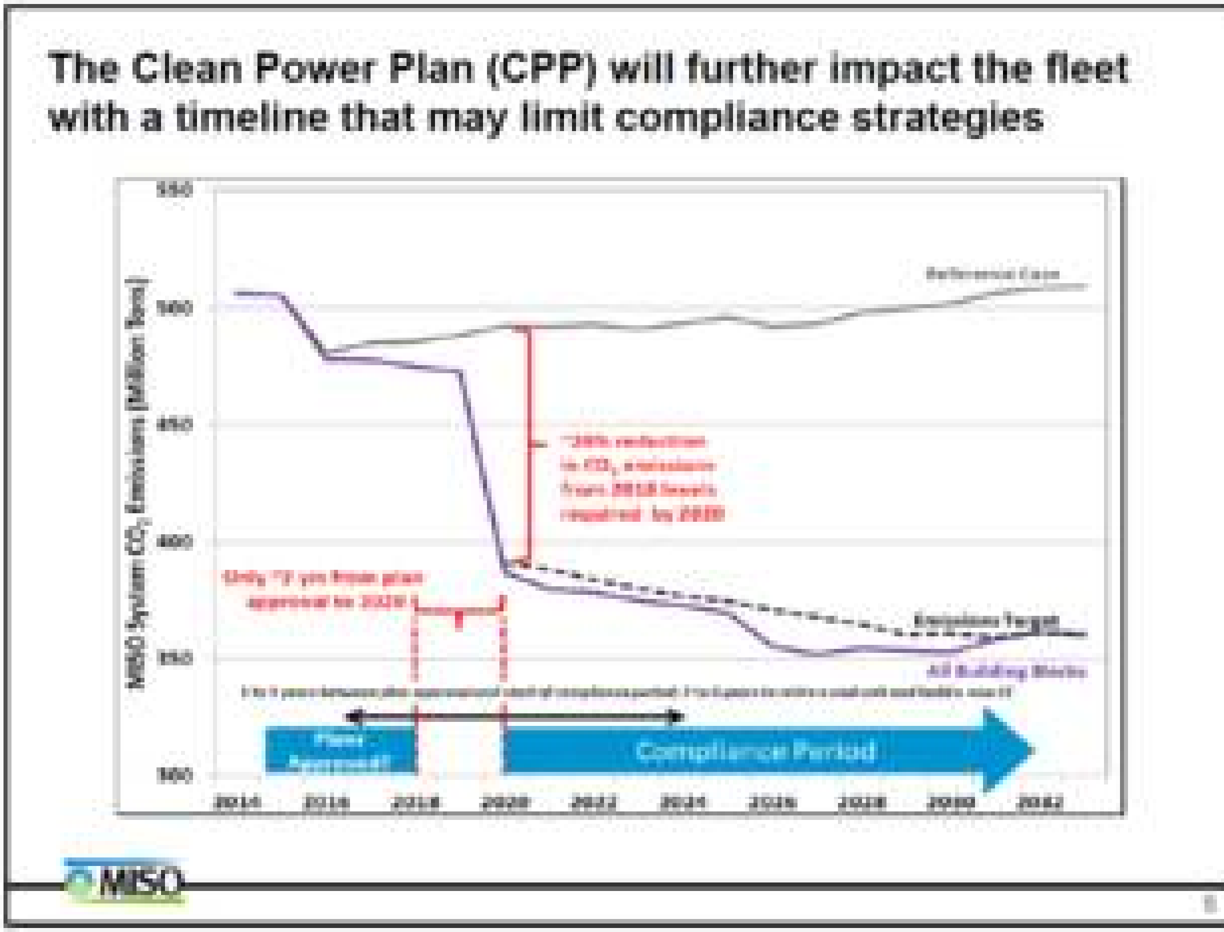

The generation fleet in MISO is affected by multiple environmental regulations
MATS
CSAPR & CWIS
Draft Clean Power Plan
NAAQS & Coal Ash
Nature of Regulation
Mercury and Air Toxics Standards
Cross State Air Pollution Rule and Cooling Water Regulations (316(b))
CO_2 from existing and new power plants
New air quality standards/ Coal ash storage
Compliance Dates
2015 / 2016
As early as 2015
2015/16 (New) Beginning in 2020 (Existing)
???
Impacts
• Significant coal retirements
• Outage coordination challenges
• Shrinking reserve margins around MISO
• Growing dependence on natural gas
• NO_x requirements tightened
• Higher plant compliance costs influence retirement decisions
• New coal requires CCS; baseload capacity options reduced
• Significant coal retirements
• Increased dependence on gas and carbon neutral resources
• Increased costs
• Other potential impacts depend on regulations
MISO

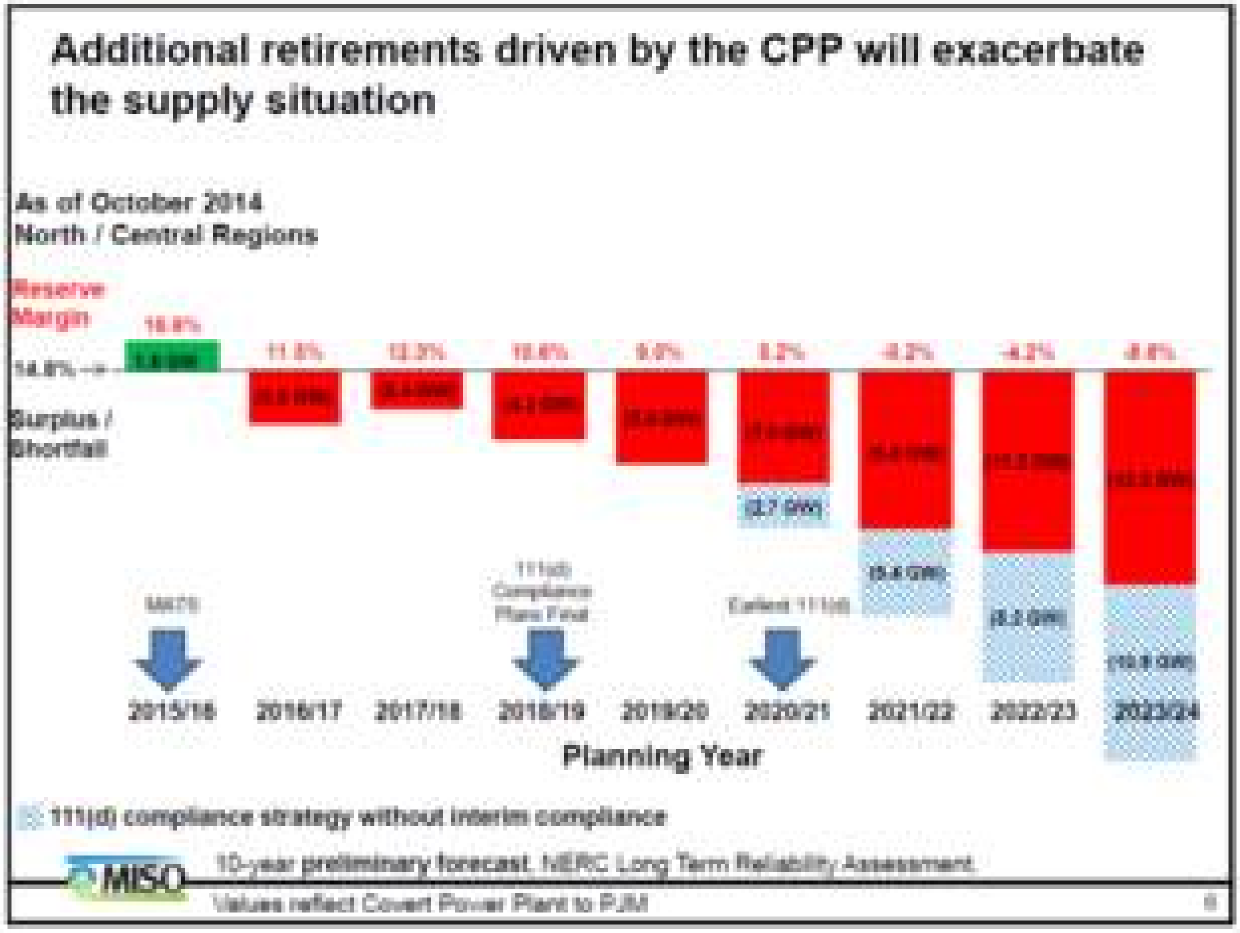
Current projections illustrate resource adequacy risk

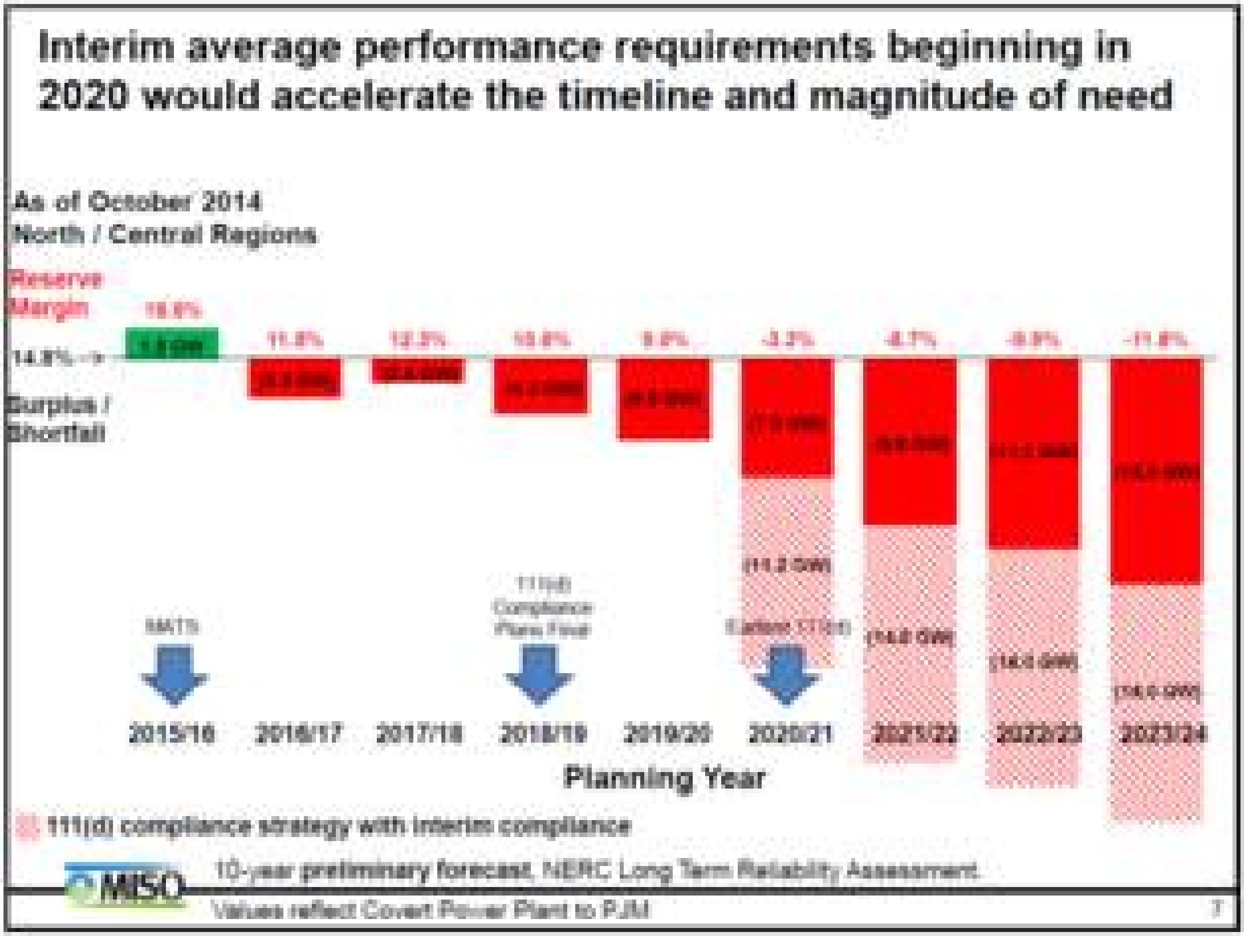
As of October 2014




The region is showing a need for additional resources to meet projected load growth (0.8%)
As of October 2014
North / Central Regions
Reserve Margin
Surplus / Shortfall
MATS
111(d) Compliance Plans Final
Earliest 111(d)
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
Planning Year
MISO
10-year preliminary forecast, NERC Long Term Reliability Assessment
Values reflect Covert Power Plant to PJM


The Clean Power Plan (CPP) will further impact the fleet with a timeline that may limit compliance strategies
Reference Case
Emissions Target
Compliance Period
MISO


Additional retirements driven by the CPP will exacerbate the supply situation
As of October 2014
North / Central Regions
Reserve Margin
Surplus / Shortfall
(2.7 GW)
(5.4 GW)
(8.2 GW)
MATS
111(d) Compliance Plans Final
Earliest 111(d)
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
Planning Year
111(d) compliance strategy without interim compliance
MISO
10-year preliminary forecast, NERC Long Term Reliability Assessment
Values reflect Covert Power Plant to PJM


Interim average performance requirements beginning in 2020 would accelerate the timeline and magnitude of need
As of October 2014
North / Central Regions
Reserve Margin
Surplus / Shortfall
(11.2 GW)
MATS
111(d) Compliance Plans Final
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
Planning Year
111(d) compliance strategy with interim compliance
MISO
10-year preliminary forecast, NERC Long Term Reliability Assessment
Values reflect Covert Power Plant to PJM

MISO is engaged to ensure reliability risks from the plan are understood and mitigated

- Filed comments requesting EPA flexibility in November
  - Focused on reliability; cumulative impact of retirements has the potential to stress transmission system reliability
  - Insufficient time available to plan and implement new generation, transmission and natural gas infrastructure
- Participating in FERC Technical Conferences
  - FERC will address reliability, markets and energy infrastructure
  - National conference at FERC's offices on February 19; regional meeting scheduled for March 31 in St. Louis
- Preparing for increased utilization of gas generation
  - Currently participating in cross-industry discussion on misalignment of gas and electric market timelines
  - Improved communication and coordination with pipeline operators
  - Pipeline status information made available to MISO Operators
  - Lack of product harmonization remains a challenge

We are reviewing our processes and procedures to ensure they promote reliability

- Transparency via annual OMS-MISO survey
- Evaluate seasonal resource accreditation
  - Demand response
  - Reliable fuel supply
  - Deliverability
- Explore transition to EPA MATS compliance
  - Six-week timing gap
  - Product and exchange facilitation
- Evaluate implications of adjacent market rule changes
  - PJM capacity performance initiative
  - Inter-market deliverability
- Assessing alignment of processes and procedures
  - Resource Adequacy
  - Outage coordination
  - Interconnection and disconnection (retirement) process
  - Transmission service requests
  - Zonal modeling

MISO

The reliable transfer of resources inter-regionally holds benefit for end-users

Collaboration with our neighbors is ongoing; regional stakeholder differences complicate seams progress

- PJM
  - Discussion of options to ensure interface prices appropriately reflect congestion costs continue
  - Coordinated planning study underway to evaluate historical congestion and identify solutions for regional approval in 2015
  - Interregional Order 1000 filing conditionally accepted by FERC
- SPP
  - Market-to-Market with SPP approved by FERC to begin on March 1
  - Progress toward a resolution being made on the JOA dispute
  - Jointly screening stakeholder submitted transmission solutions to historical congestion issues as part of our coordinated planning effort
- Joint Parties (Southern Company, TVA, Associated Electric, PowerSouth, LGE/KU)
  - Working with parties on short-term extension of Operations Reliability Coordination Agreement (ORCA) and on long-term protocols for coordination and operation post-ORCA

MISO

MISO focus is broad in response to the nation's changing energy landscape

- **Environmental Regulations –** managing transition to Mercury and Air Toxics Standards (MATS) and preparing for Clean Power Plan (111(d))
- **Resource Adequacy** – efforts being taken to ensure adequacy throughout entire year and accommodate a changing portfolio
- **MISO Processes and Procedures –** review / revise to align as industry continues to evolve
- **Seams Management and Optimization** – enhancing reliable movement of resources to minimize cost to end user

RECEIVED
October 31, 2014
INDIANA UTILITY
REGULATORY COMMISSION

Indianapolis Power & Light Company

2014 Integrated Resource Plan

Public Version

October 31, 2014

construct with a seasonal construct or to add seasonal capacity products. A Seasonal Construct is favored by utilities with an obligation to serve as aligns better with its obligations to customers, allows utilities to better adapt changing market, business, and regulatory landscapes, and addresses the winter peaking issues of natural gas. IPL is a leader in the resource adequacy related stakeholder process and actively provides substantive comments to MISO to influence change in the best interests of our customers.

Planning Reserve Margin Modeling

IPL's minimum PRMR established by MISO for 2014 equates to an effective 14.8% reserve margin, representing an increase from 2012 (13.1%) and 2013 (14.2%). As identified above, many factors are used by MISO to establish an LSE's resource adequacy requirement. The LSE's planning reserve margin changes annually as MISO modifies its LOLE analysis and as a result of changes in its EFORd and diversity. IPL's ICAP ratings can also change annually due to the results of unit testing. For Ventyx's long term modeling purposes in this IRP, IPL identified a 14% planning reserve margin to be used consistent with IPL's summer-rated capacity. This long-term modeling number provides for targeted reserves in the range of future expected MISO-determined resource needs and is consistent with the MISO specific calculations shown in Figure 4.3.

Planning Year beginning June 1, 2015 and ending May 31, 2016

IPL is retiring its Eagle Valley units 3 through 6 by April 16, 2016 to comply with its MATS deadline. However, this retirement date is 6.5 weeks before the end of the 2015-2016 MISO Planning Year. MISO's current resource adequacy requirement states a capacity resource that clears a planning reserve auction must be available during the entire commitment period otherwise replacement capacity from the same zone must be secured to avoid tariff compliance penalties levied by FERC. During this 6.5 week low load period IPL has capacity in excess of its requirement to reliably serve its load. The requirement to buy additional capacity is unjust and unreasonable and would be merely a transfer of wealth with no impact on resource adequacy for IPL or Zone 6. In order to avoid the excess costs associated with this provision, on June 20, 2014, IPL submitted a request to FERC to waive the replacement requirement needed during the stated 6.5 week timeframe. With the support of the IURC comments filed with FERC, this request was granted by FERC on October 15, 2014. As a result of FERC granting the Waiver Request, IPL and its customers will not be forced to bear the costs of unneeded capacity.